There are instances when the cost of the actual study is expected to exceed the initial study deposit. In those situations, MISO will request the customer to deposit additional funds to ensure that the Facility Study continues per schedule. If the customer fails to make any additional deposit, MISO will stop all work until the additional deposit is received.

5.4.3 Performing the Facility Study

MISO planning staff will form an Ad Hoc Study Group as provided in Section 5.5.1. MISO then prepares the study cost estimate, project timeline, and study agreement.

i. MISO Planning contacts the impacted area (i.e., Local Balancing Authority Area where the constraint is located) and, if required, a third party contractor to determine Ad Hoc Study Group membership and cost estimates
ii. MISO Planning will initiate and coordinate the Ad Hoc Study Group Facility Study process.

The Facility Study report will determine a good faith estimate of the following:

i. The cost of direct assignment facilities to be charged to the transmission customer
ii. The transmission customer's appropriate share of the cost of any required network upgrades
iii. The time required to complete such construction and initiate the requested service.

After the Facility Study report is complete, it is reviewed by MISO planning staff before it is transmitted to the customer. At this juncture, the transmission customer has the following options.

i. It can either opt for a reduced amount of available transmission service, as identified in the SIS report.
ii. Proceed with a Facility Construction agreement and agree to fund and build the transmission upgrades for the full requested amount which caused the Facility Study to be performed.
iii. Withdraw the TSR

Specification Sheets

Prior to MISO moving the request to an ACCEPTED status, an executed Specification Sheet must be received from the customer. The Specification Sheet gives the details of the service, including the specific source, sink, term of the transaction, amount, and lists any prerequisite conditions that must be met prior to commencement of service, such as Network Upgrades. Once the customer is notified via OASIS, they will have 15 Calendar Days to provide those forms or the service will be deemed withdrawn and the request will be refused.

5.4.4 Facilities Construction Agreement

When the results of the Facilities Study indicate the need for the Transmission Customer to finance the construction of Network Upgrades, those requirements will be memorialized in a 3-party Facilities Construction Agreement which must be filed at FERC either executed or unexecuted prior to commencement of the transmission service. This agreement will delineate the roles and responsibilities of each party to the agreement.

5.5 Miscellaneous

5.5.1 Ad Hoc Study Group

Under the direction of MISO, the Ad Hoc Study Group will participate in the analysis and reporting of the available transmission capacity to accommodate the transmission service request. The Ad Hoc Study Group will perform, as necessary and in accordance with the provisions of the Tariff, System Impact and Facilities Studies. MISO will form and direct the activities of the Ad Hoc Study Group. It is anticipated that the study group formed to evaluate a transmission service request will be made up of representatives from the source and sink Local Balancing Authority Areas as well as interested intervening Local Balancing Authority Areas. It is anticipated that MISO will perform preliminary distribution factor calculations or other analysis to determine the extent of interactions with intervening systems. The Ad Hoc Study Group may also include third party contractors to assist in performing the analyses.

The possible participants in System Impact and subsequent Facilities Studies will include:

1. Transmission Customer
2. MISO planning staff
3. Transmission Owners of facilities potentially impacted by the request
4. Adjacent transmission providers/RTO(s)
5. Regional or subregional study groups in place in the areas potentially impacted by the request

The role of MISO planning staff will generally be to:

1. Establish study time line – Tariff defined
2. Prepare the study agreements
3. Provide the system models to be used in studies
4. Provide the study guidelines by which studies should be performed
5. Determine whether an impact study is needed to resolve constraints to accepting service
6. Ensure the accuracy of studies, either by MISO planning staff, or on behalf of MISO by contractors or members of the Ad Hoc Study Group
7. Coordinate the formation and activities of the Ad Hoc Study Group
8. Review any studies performed on behalf of MISO for accuracy and for compliance with the Tariff and applicable standards and procedures
9. Provide study results and reports to customer
10. Handle billing and payment of study costs

The role of other participants in the studies will generally be to:

1. Indicate desire to participate in the Ad Hoc Study Group
2. Provide information to MISO to assist in preparing study agreements
3. Assist in updating any models used for studies
4. Perform studies, or aspects of studies, as requested by, and on behalf of, MISO according to study guidelines of MISO, and applicable standards
5. Provide review and comments to MISO of study results with regard to their systems
6. Provide study results and reports to MISO
7. Respond to MISO questions and assist MISO in responding to customer questions concerning study results

Note: If transmission service is being requested across the border between PJM and MISO, the procedures under "Joint and Common Market," as provided at the following web-link, will be invoked:
http://www.midwestmarket.org/publish/Folder/2220c2_108155d446d_-72290a48324a?rev=1
If MISO finishes its SIS or the Facility Study before the customer has received the results for the other leg of the transmission service, then MISO will wait to request the transmission service specification sheets until the customer has results from both transmission providers (PJM and MISO). Once the results from PJM's planning department are available, MISO will request the customer to submit the Specification Sheets within 15 Calendar Days after initiating the request. Customer's failure to submit the Specification Sheets within 15 Calendar Days will result in the refusal of the TSR on MISO's OASIS.

5.5.2 Redispatch Options

The transmission customer does have the option for requesting MISO to perform a re-dispatch option study during the SIS phase. The goal of this additional step of analysis is to find out which generators, within MISO and external to MISO, can be re-dispatched in real time to mitigate transmission constraints. If the customer requests this information, then the MISO planning staff will provide a list of all units that affect a particular constraint with their respective distribution factors on the constraints. MISO planning staff does not perform this analysis if not requested by the customer. If the transmission customer wishes to utilize re-dispatch option then it will be disqualified to request ARRs and FTRs as documented in Module B, Section 13.5, of the Tariff.

5.5.3 Group TSR Studies

If multiple customers request TSRs on a common path due to economic or other engineering reasons, MISO shall study all those TSRs in one single group and shall call it a single group study. The cost to perform the System Impact Study and Facility Study shall be prorated based on the individual size of each TSR in the group. The appropriate percentages to calculate the prorate costs to perform the studies shall be shared amongst all the transmission customers at the commencement of the study. The percentage costs for any common upgrades will also be calculated based on the prorate share of the size of the TSR. Any other transmission upgrades costs that are unique to each TSR in the group will be direct assigned to that TSR's customer.

5.5.4 Specification Sheets

Prior to MISO moving the request to an ACCEPTED status, an executed Specification Sheet must be received from the customer. The Specification Sheet gives the details of the service, including the specific source, sink, term, amount, and lists any prerequisite conditions that must be met prior to commencement of service, such as Network Upgrades. Once the customer is notified via OASIS, they will have 15 Calendar Days to provide those forms or the service will be deemed withdrawn and the request will be refused.

5.5.5 Provisional Generator Interconnection Agreements.

Point-to-Point transmission service is available for units with provisional interconnection agreements. Network Integrated Transmission Service is not available to units with provisional interconnection agreements.

5.6 Appropriate Links

OASIS Transmission Studies page. Contains links to the following pages and reports:

- System Impact Studies page which contains links to reports.
- Facility Studies page which contains links to the reports.

FERC metrics report links.

https://oasis.midwestiso.org/documents/MISO/Performance_Metrics.html

AFC procedure links:

https://oasis.midwestiso.org/documents/MISO/TP-OP-005-r5%20Available%20Transfer%20Capability%20Implementation%20Document.pdf

MISO Network and Point to Point Specification Sheets:

https://oasis.midwestiso.org/documents/miso/network_point.html

Tariff and Rate Schedules

https://www.misoenergy.org/Planning/LongTermTransmissionService/Pages/Schedules.aspx

Transmission Services webpage

https://www.misoenergy.org/Planning/LongTermTransmissionService/Pages/LongTermTransmissionService.aspx

6 Other Non-cyclical Planning Studies

6.1 Out-of-Cycle Project Review

The out-of-cycle project review is not intended to replace the MTEP study program. The expedited out-of-cycle review process is established under the Transmission Owner's Agreement as a means to address projects that cannot wait for the cyclical MTEP process. The MTEP process is intended to provide an orderly and efficient, holistic, open, and transparent expansion planning process; out-of-cycle review allows for exceptions to the preferred MTEP program. These project review guidelines exist specifically to define procedures for evaluating additions or modifications of transmission lines, transformers, other substation equipment, or load additions that have immediate analysis requirements that cannot be completed through the preferred MTEP process.

Project evaluation will still include normal review procedures, including:

- Determining if the Transmission Owner has already performed his own studies that can be used as input to MISO project review.
- Stakeholder (SPM and PS) notification of urgent project needs.
- Determining if the project is eligible for cost sharing under the Tariff.
- Screening the project for approval by ensuring that planning criteria are observed with the project in place.
- Reviewing the project (if it is eligible for cost sharing) to validate the system need for the project against applicable reliability and economic criteria.
- Confirming that the project criteria are applicable under the Tariff, and establishing it as either a Baseline Reliability Project (BRP) or Market Efficiency Project (MEP), or Other Project.
- Determining the project's applicable cost allocation under the Tariff.
- Reviewing the project for approval (if it does not meet BRP or MEP requirements) by ensuring that planning criteria are observed with the project in place.
- Reviewing needs analysis and cost allocation (if applicable) with stakeholder groups.

In order to complete out-of-cycle analyses in a reasonable time frame and in parallel with ongoing MTEP processes, the party submitting the proposed projects will be responsible for demonstrating that the project does not result in any violations of applicable planning standards, and providing this demonstration to MISO for review.

6.1.1 Entity Documentation of Need

The Transmission Owner is responsible for submitting an out-of-cycle review report that documents the system need for a proposed project. The report must include a description of system conditions causing contingency criteria violations. The report should also detail any alternatives and the rationale for selecting this project over alternative projects. MISO planning staff will confirm receipt of the report and project data. Upon receipt of the report, MISO will perform a cursory review of the submittal and, if necessary, request additional information.

6.1.2 Project Eligibility for Cost Sharing under the Tariff

The Transmission Owner's review report must clearly identify individual projects. A project must address a related group of system needs, and must be able to be operated without adversely impacting the Transmission System. MISO planning staff will confirm the existence of the system need, and the effectiveness of each project in addressing that need. MISO planning staff will then determine the eligibility for cost-sharing for each project based on applicable Tariff project costs.

6.1.3 Project Need and Effectiveness Validation

MISO will validate each project's need by analyzing relevant system conditions and contingencies without and with the proposed project. MISO will confirm that the project efficiently addresses the system need. MISO may evaluate alternative projects and discuss them with the Transmission Owner.

6.1.4 Project Criteria Violations

The Transmission Owner must complete two system study cases: the first without the proposed project and the second with the proposed project in place and operating as planned. Each case must use either an automated contingency screening analysis process such as the PSS/E ACCC, or a manual contingency analysis process. These models may include different years, seasons, and load levels. The models and contingency files must be consistent with the MTEP process, and will be chosen such that they constitute a complete representation of potential violations associated with the proposed project. The Transmission Owner must also determine if other types of study cases are necessary (i.e., stability or short circuit).

The first study case (excluding the proposed project) analyzes pre-contingency and post-contingency conditions, and should show violations of NERC criteria, such as overloaded facilities and over and under voltages. Any violations will be flagged and listed in the contingency analysis output as a pre-existing condition. The second case (including the proposed project) analyzes the same pre-contingency and post-contingency conditions as the first, and again identifies any violations of NERC criteria. The results of the first and second study cases are compared to each other to determine the relative impact of the proposed project on the system. Any new criteria violations on any MISO member or neighboring systems resulting from the project must be documented. MISO will review the Transmission Owner's contingency results. MISO planning staff may accept this analysis or, if necessary, perform independent validation.

6.1.5 Project Type Categorization for MTEP

MISO will review the project and categorize it so that it can be included in the MTEP Database. This categorization process also determines if the project is eligible for the Tariff cost-sharing process, as described in Section 8.

6.1.6 Project Cost Allocation & Stakeholder Review

MISO will determine the cost allocation applicable for each project once the current MTEP cycle is completed. Prior to the MTEP cycle, MISO will inform the Transmission Owner regarding the applicable cost allocation methodology per Attachment FF of the Tariff (*e.g.,* as a percentage postage stamp and percentage sub-regional LODF). If the project is subject to regional cost sharing per Attachment FF, the project will be presented to stakeholders for review prior to going to the Transmission Provider Board for approval.

6.1.7 Project Approval Status

MISO will inform the Transmission Owner of each project's approval status as well as its categorization for cost allocation. The Transmission Owner should review the project approval status and contact MISO planning staff with any questions or comments.

6.2 System Support Resource (SSR) Studies to Evaluate Unit De-commissioning

6.2.1 Introduction

System Support Resources (SSR) are Generation Resources or Synchronous Condenser Units (SCUs) which are required by MISO to "maintain system reliability, if such Generation Resources or SCUs are uneconomic to remain in service and otherwise would be decommissioned, placed into extended reserve shutdown or disconnected from the MISO region."

The SSR procedure includes the following steps:

1. Market Participant (MP) who is planning to retire or mothball his owning/operating Generation Resource or SCU located in MISO region, must submit a completed Attachment Y to MISO at least twenty-six weeks prior to taking such steps;
2. A detailed reliability study will be performed for the SSR study. Any valid reliability violations will be cited if they are caused by the retirement of the generator/SCU;
3. Before a Generation Resource or SCU is justified for SSR status, other feasible alternatives such as generation re-dispatch, system reconfiguration, transmission project acceleration, new transmission project, new generator resource or SCU installation, remedial action plans, or Demand Side Management (DSM) will be assessed. Only when there is no identified applicable alternative which is more economical than the operation of SSR unit, MISO and the Market Participant shall enter into an SSR Agreement with Attachment Y-1. Otherwise, the Generation Resource or SCU will be approved for retirement;
4. The SSR unit will be operated based on the established terms in Attachment Y-1, and costs to compensate an SSR units will be allocated to the Load Serving Entity that benefits from the operation of the SSR unit, which is determined by the SSR study; and

5. MISO shall annually review the reliability requirements and determine whether the SSR agreements should be extended.

MISO will evaluate the performance of the Transmission System against applicable reliability standards/criteria to determine the SSR status when the Market Participant owning or operating such a facility submits a completed Attachment Y to the Tariff. Before SSR status is justified, other alternatives should also be considered to determine the most economical and feasible solution. These alternatives include generation re-dispatch, system reconfiguration, transmission additions, new generator resource or SCU installation, remedial action plans, or demand response solutions.

6.2.2 Power Flow Model Preparation

At least two sets of models will be prepared for the SSR study: the near-term model which represents the year the generation resource or SCU is to be retired, and the mid-term model which typically represents the five-year ahead outlook. The models are based on contractual dispatch, with firm transactions appropriately modeled and Network Resources economically dispatched in each balancing area. Normally, the mid-term model is developed from the latest MTEP model, and the near-term model is developed from the latest series of MISO model. Both models are updated with latest updates and corrections. Typically, summer peak model will be chosen for the SSR study. In areas where other situations are deemed necessary, the models which represent these situations will be picked as additions.

For each model, two scenarios will be created which represent the "before" and "after" generator/SCU retirement states. The models which represent these two scenarios are created in the following steps:

Step 1: The "after" retirement model should be created first as follows:

a) Using a model representing the year of interest, create a balancing area, merit order generator dispatch that excludes the unit(s) to be retired (i.e. the unit(s) will be off-line).
b) The "after" retirement model is now complete.

Step 2: The "before" retirement model should be created from the "after" retirement model since the reliability violation difference between these models are to be compared.

a) Renumber the control area of any on-line generation in the balancing area of interest that is located at the same physical plant site or the electrically equivalent site as the to-be-retired units. This step is necessary to avoid re-dispatching these units in the next step.
b) Scale down the generation in the balancing area of interest equal to the "to-be-retired" unit(s) amount.
c) All generators whose control area was renumbered in step 2a) above should now be moved back into the control area of interest.
d) Turn on the unit(s) to be retired.
e) Check swing machine in the event that a large unit retirement results in a substantial control area loss change.
f) The "before" retirement model is now complete.

6.2.3 Reliability Evaluation

System Intact (Category A) and single-element contingencies (Category B) will be considered in the evaluation, which are consistent with NERC Planning Standards I.A. Category B includes any single transformer, generator, or transmission line outage. In addition, significant multiple-element contingencies consistent with NERC Category C will be reviewed.

NERC Transmission Planning Standards TPL-001, TPL-002, and TPL-003 effective April 1, 2005 will be applied to test the system. In performing the SSR study, Regional, State, and MISO Member (Local) planning criteria will be respected. In addition to NERC Standards, load deliverability will be tested in areas with potential load deliverable deficiency. A 1 day in 10 year LOLE criteria will be applied.

The reliability evaluation for the SSR study is described below:

- All 69 kV and above facilities in the balancing area where the candidate retired unit is located are monitored. 100 kV and above facilities in other neighboring balancing areas (with direct ties) are also monitored.
- Branch loading is tested against its normal thermal rating for Category A condition (system intact), and against its emergency thermal rating for Category B and C contingencies.

- Steady state bus voltage criteria specified in "MISO Voltage and Reactive Management Process Phase I - Effective 7/1/04" are adopted, with respect to a MISO Members' (Local) voltage criteria. Generally, pre-contingency voltage limitation is between 1.0 and 1.07 p.u. for 500 kV and above buses, and between 0.95 and 1.05 p.u. for buses below 500 kV. Post-contingency voltage limitation is normally between 0.9 and 1.1 p.u., if it is not specified. All 100 kV and above post contingent voltages are assessed after automatic transformer tap change and shunt switching have been performed.
- Under system intact and category B contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" retirement scenario is equal to or greater than:
  a) 5% of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" retirement scenario; or
  b) 3% of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" retirement scenario.
- Under system intact and category B contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" retirement voltage calculation.
- Under category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, or load shedding will be considered if applicable.
- In areas with potential load deliverable deficiency, load deliverability study will be performed. The criteria of 1 day in 10 year LOLE will be applied.
- Angle/voltage stability studies will be performed if necessary.

6.2.4 Alternatives Evaluation

Before a Generation Resource or SCU is justified for SSR status, other feasible alternatives such as generation redispatch, system reconfiguration, transmission project acceleration, new transmission project, new generator resource or SCU installation, remedial action plans, or Demand Side Management (DSM) will be assessed. Only when there is no identified applicable alternative which is more economical than the operation of SSR unit, MISO and the Market Participant shall enter into an SSR Agreement with Attachment Y-1. Otherwise, the Generation Resource or SCU will be approved for retirement.

6.2.5 Report Writing

After the SSR study is finished, a detailed study report will be drafted and archived. A letter with final SSR study decision will be mailed to the Market Participant who is applying for the retirement or mothball of Generation Resource or SCU.

7 Cost Allocation Process

Attachment FF, Section III of MISO's EMT presents the Designation of Cost Responsibility for MTEP Projects, which describes the project cost allocation process to all Market Participants and Transmission Customers. The provisions and requirements of the cost allocation process are summarized in the following sections of this Business Practice Manual. Readers and users of this Manual are advised, however that the authoritative document for project cost allocation remains the Tariff.

7.1 Baseline Reliability Projects

Transmission expansion projects that serve a documented need for baseline reliability are eligible for MTEP cost-sharing if they: 1) have a total cost of $5 million or more; or 2) have a project cost below $ 5 million, but a total cost that is 5% or more of the Transmission Owner's net plant as established according to Attachment O.

All costs for Baseline Reliability expansion projects with a rated voltage of 100kV through 344kV are allocated to Transmission Customers in designated sub-regional pricing zones. The sub-regions and pricing zones are determined on a case-by-case basis using the Line Outage Distribution Factor (LODF) process described in Appendix J of this BPM. With this process, Transmission Customers that benefit from the expansion project are allocated costs proportional to the benefit received.

For Baseline Reliability expansion projects with a rated voltage of 345kV or higher, twenty percent (20%) of the costs are allocated to all pricing zones. The remaining 80% of project costs are allocated sub-regionally to all Transmission Customers within designated pricing zones. As before, the sub-regions and pricing zones are determined on a case-by-case basis using the LODF process described in Appendix J of this BPM. The 20% - 80% split on project costs reflects a MISO planning staff assessment that projects rated 345kV or higher improve system reliability and power flow characteristics for all Transmission Customers across the MISO footprint.

Line Outage Distribution Factor (LODF)

As described above, 20% of approved Project Costs are allocated on a system-wide basis to all Transmission Customers. The remaining 80% of Project Costs are allocated to Transmission Customers in designated pricing zones on a case-by-case basis using the LODF method.

The LODF method first determines the impact of a new facility planned as part of an expansion project on other, existing components for a defined region. MISO planning staff uses the PSS/E MUST software to estimate power flow under two scenarios: the first includes the proposed new facility, and the second excludes the proposed facility. The LODF is then calculated as the absolute value of the estimated percentage change in power flow over existing components between these two scenarios. Where a project consists of multiple facilities, each one is tested for its effect on the existing system.

Equation 8.1 - 1

$$LODF = Abs\left(\frac{(PF_2 - PF_1)}{PF_2}\right)$$

Where: PF_2 = Estimated power flow on existing facilities excluding the expansion project
PF_1 = Estimated power flow on existing facilities including the expansion project

As an example, consider an existing circuit where the estimated power flow under given operating conditions is 100 MW. A proposed expansion project adds facilities such that the estimated power flow on the existing circuit is reduced to 90 MW under identical operating conditions. The LODF for the existing circuit is 10%, as calculated using Equation 8.1-1 as follows: (100 MW – 90 MW)/100 MW = 10%.

The MUST software calculates estimated power flow "with and without" the proposed expansion project for each existing component within the MISO footprint rated at 100 kV and above. In the event that a component's LODF is less than 1% (e.g., the monitored component's power flow changes by less than one percent with the addition of the proposed expansion project), the component is excluded from further cost allocation calculations.

The LODF is then applied to each affected existing component according to the mileage rating of the component. A cost allocation value, called the "Sum of Absolute Value of LODF-Mile" ("LODF-Mile"), is calculated by multiplying the LODF times the mileage, for each component affected by a given expansion project. Transmission Owners are expected to provide line length (in miles) for all transmission system components. Where the component mileage is not available, MISO planning staff estimates mileage using model impedance values and typical impedance per mile rates for similar components. Transformers are given a designated mileage rating of one mile.

The additional criteria used in the calculation of cost allocations for Baseline Reliability Projects are described in Appendix J of this BPM.

7.2 Generation Interconnection Projects

Generation Interconnection Projects are Network Upgrades associated with interconnection of new, or increase in generating capacity of existing, generation under Attachments X to the Tariff. These projects are driven by interconnection study procedures and agreements. Interconnection Customer is responsible for 100 percent of the costs of Network Upgrades rated below 345 kV and 90 percent of the costs of Network Upgrades rated at 345 kV and above (with the remaining 10 percent being recovered on a system-wide basis.

7.3 Transmission Delivery Service Projects

Facilities for Transmission Service projects are designated as Direct Assignment or Network Upgrades. Transmission expansion project costs that are designated to Direct Assignment Facilities are allocated to the specific Transmission Customer requesting the service. Costs for Network Upgrade projects are rolled into the MISO facilities rate base until the Transmission Owner is allowed to recover the costs in its own facilities rates.

7.4 Market Efficiency Projects

A Market Efficiency Project can be proposed by MISO, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities and shown to provide market efficiency benefits to one or more Market Participant(s), but not determined to be a Multi Value Project, and provides sufficient market efficiency benefits to justify inclusion into the MTEP.

The Tariff establishes that an MEP may be eligible for cost sharing as an MTEP transmission expansion project if it has a rated voltage of 345kV or above, has total project costs of $5 million or more, and can demonstrate regional benefit metric, multiple future scenarios, and multi-year analysis as described in Sections 8.4.1 and 8.4.2 below.

Twenty percent (20%) of the cost for a Market Efficiency Project is allocated to all Transmission Customers through a system-wide rate. The remaining 80% of the project cost is allocated to all Transmission Customers in each of MISO's seven Local Resources Zones, see Attachment WW of the Tariff. The cost allocated to each of these Local Resource Zones is based on the relative benefit each receives from the project, as determined by the economic benefit analysis process described in Sections 8.4.1 and 8.4.2 below. Also, a key provision of the cost allocation method is the "No Loss" provision. This "No Loss" provision is intended to protect customers in a Local Resource Zone from being allocated costs where they may not benefit from the project. Local Resource Zones that are not shown to receive net benefits from the Market Efficiency Project will be excluded from the allocation of the 80% component of project cost.

If MISO planning staff determines that a specific project meets the criteria of both a Baseline Reliability Project and a Market Efficiency Project, the project cost is allocated using the Market Efficiency Project allocation procedures.

7.4.1 Economic Benefit Metric

The criteria to determine whether a project should be included as a Market Efficiency Project is based on multiple future scenarios and multi-year analysis guided by input from all stakeholders. The benefit metric will use a weighted futures, no loss (WFNL) metric to analyze the anticipated annual economic benefits of construction of a proposed Market Efficiency Project to Transmission Customers in each of the Local Resource Zones based upon adjusted production costs (APC). APC savings will be calculated as the difference in total production cost of the resources in each Local Resource Zone adjusted for import costs and export revenues with and without the proposed Market Efficiency Project as part of the Transmission System. The WFNL metric for each Local Resource Zone will be calculated using the weighted APC savings determined for each future scenario included in the analysis.

Adjusted Production Cost savings are estimated by modeling the production cost of the base case and alternative transmission system plans, and comparing each plan to several possible Future economic or operating scenarios. An example of this method is presented graphically in Figures 8.4-1 and 8.4-2, as decision trees. In these Figures, several Futures are presented showing combinations of fuel price escalation rates and load forecast projections. There are hree fuel price escalation possibilities (low, trend, and high), along with three load requirement forecasts (also low, trend, and high). The estimated probability of each possible condition is shown, and the joint probability for each resulting Future (a combination of two possibilities) is calculated.

Figure 8.4-1 presents example results for the base transmission plan production cost. Each Future has an associated total production cost and joint probability, and the expected cost (weighted by joint probability) is $536 million. Figure 8.4-2 presents a similar analysis, using an alternative transmission expansion plan. In this scenario, the modeling yields an expected cost of $526 million, using the same Futures as used for the base case. Comparing these two cases indicates that the estimated production cost savings from the alternative transmission expansion plan is $10 million.

While this example considers uncertainties around two critical inputs (fuel cost escalation and load forecast), in practice MISO planning staff may consider uncertainties for several variables, such as fuel prices, load forecasts, cost escalation rates, unit outage rates, environmental compliance costs, and unit operating constraints.

Equation 8.4-1

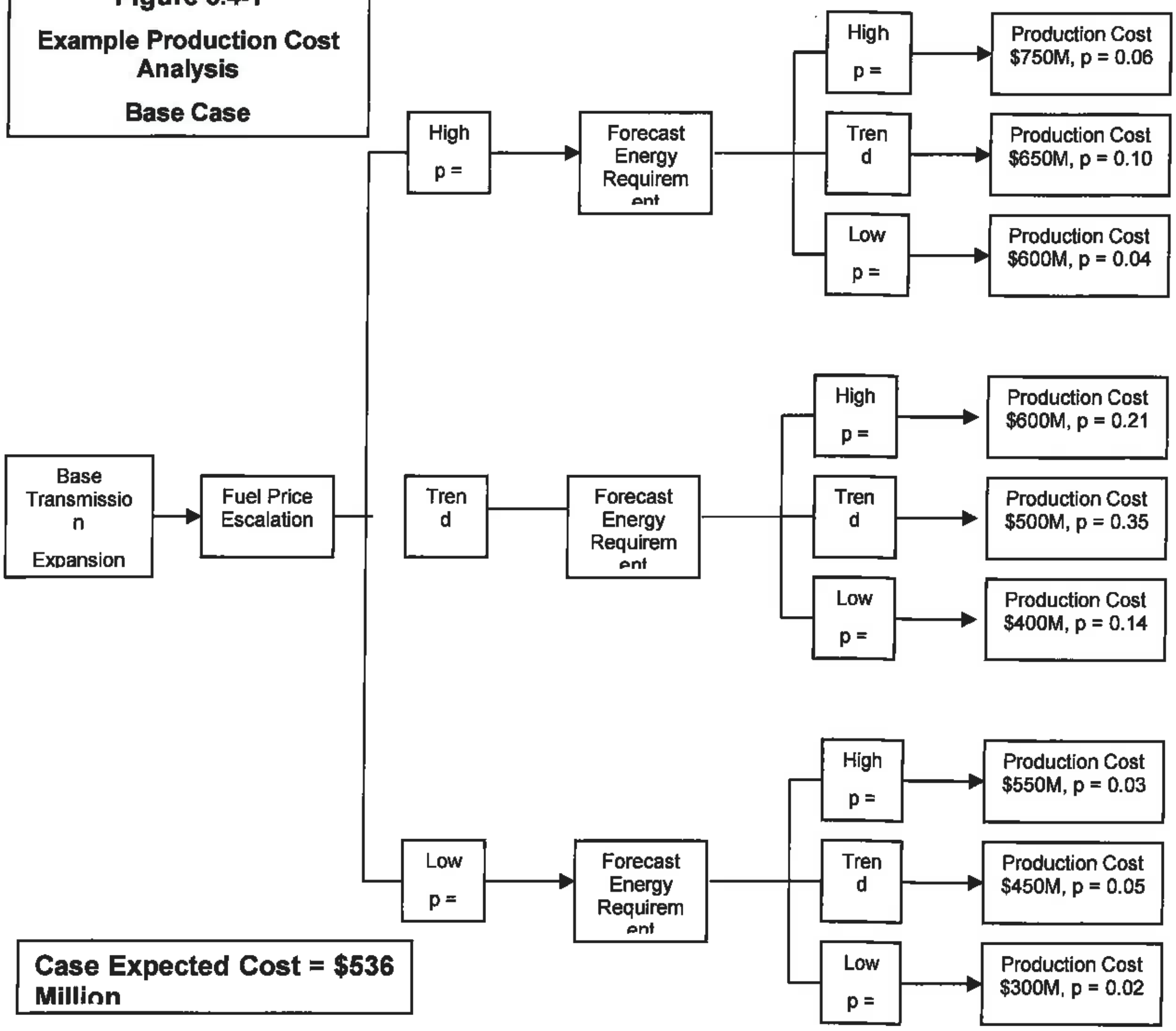
$$WGNL = (70\% APC - 30\% \; Load LMP)$$

Where: APC = Estimated savings from Adjusted Production Costs
Load LMP = Estimated savings on Locational Marginal Price at affected power delivery nodes.

Figure 8.4-1

Example Production Cost Analysis

Base Case



Case Expected Cost = $536 Million

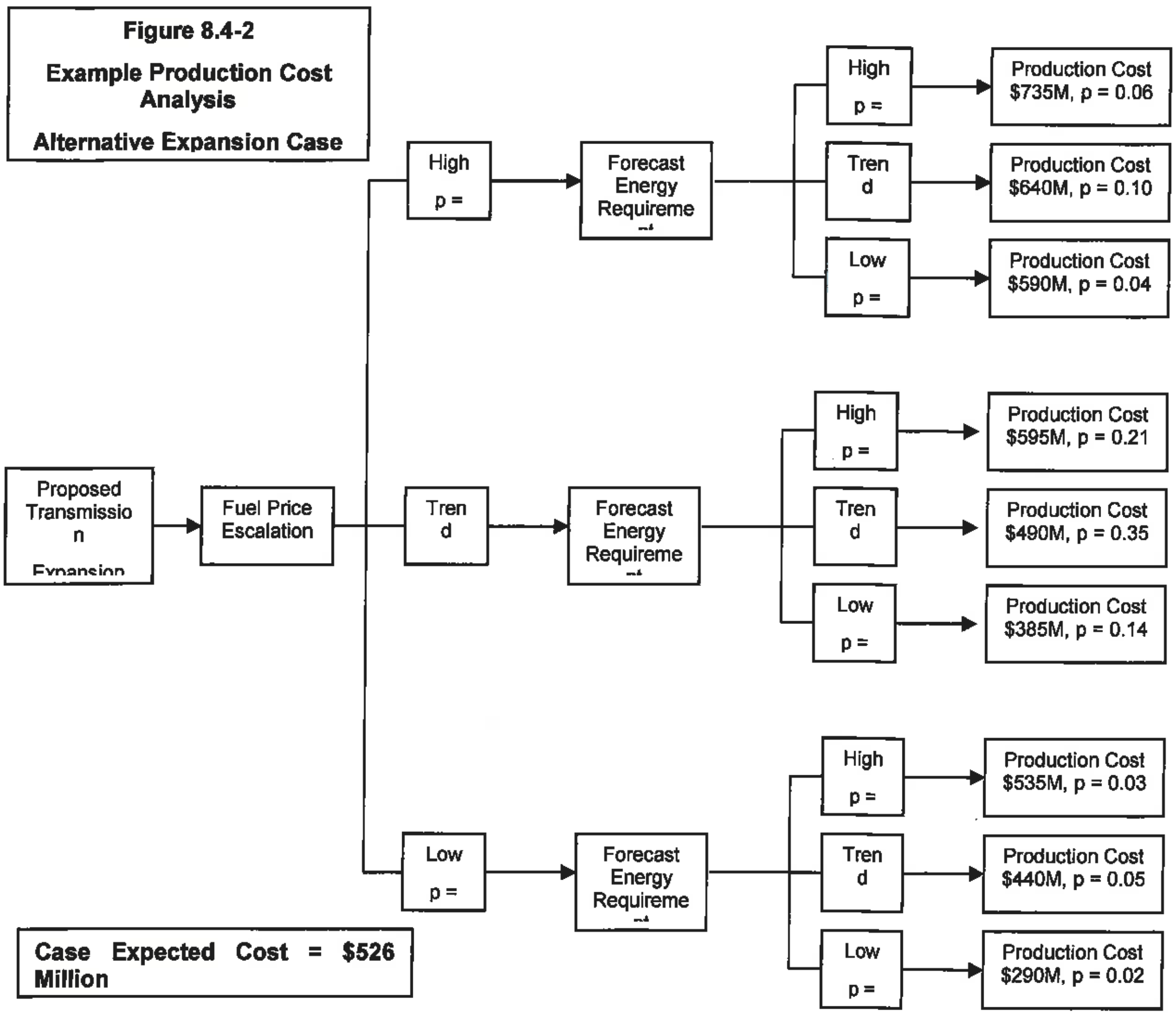


Figure 8.4-2
Example Production Cost Analysis
Alternative Expansion Case
Proposed Transmissio n Expansion
Fuel Price Escalation
High p =
Tren d
Low p =
Forecast Energy Requireme
High p =
Tren d
Low p =
Production Cost $735M, p = 0.06
Production Cost $640M, p = 0.10
Production Cost $590M, p = 0.04
Production Cost $595M, p = 0.21
Production Cost $490M, p = 0.35
Production Cost $385M, p = 0.14
Production Cost $535M, p = 0.03
Production Cost $440M, p = 0.05
Production Cost $290M, p = 0.02
Case Expected Cost = $526 Million

7.4.2 Market Efficiency Project Benefit and Cost Evaluation Methodology

Project benefit evaluations will include benefits for the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year. The annual benefit for a proposed Market Efficiency Project will be determined as the sum of the WFNL values for each Local Resource Zone. The total project benefit will be determined by calculating the present value of annual benefits for the multiple future scenarios and multi-year evaluations.

The costs applied in the benefit to cost ratio will be the present value, over the same period for which the project benefits are determined, of the annual Network Upgrade Charges for the project as determined in accordance with the formula in Attachment GG for the Transmission Owner constructing the proposed Market Efficiency Project.

The present value calculation for both the annual benefits and annual costs will apply a discount rate representing the after-tax weighted average cost of capital of the Transmission Owners that make up the MISO Transmission System.

A benefit to cost ratio test will be used to evaluate a proposed Market Efficiency Project. Only projects that meet a benefit to cost ratio of 1.25 or greater will be included in the MTEP as a Market Efficiency Project and be eligible for regional cost sharing.

The benefits of the project and the cost allocations as a percentage of project cost will be determined one time at the time that the project is presented to the MISO Board for approval. Estimated Project Cost will be used to estimate the benefit to cost ratio and the eligibility for cost sharing at the time of project approval. To the extent that the Commission approves the collection of costs in rates for Construction Work in Progress ("CWIP") for a constructing Transmission Owner, costs will be allocated and collected prior to completion of the project.

7.5 Multi Value Projects

The revised Tariff filing of July 15, 2010 incorporated a new type of cost shared project designated as a Multi Value Project (MVP). An MVP is one or more Network Upgrades that address a common set of Transmission Issues, satisfy one or more of the Criteria listed in Section 8.5.1, and satisfy all of the conditions listed in Section 8.5.2. The primary purpose of the MVP is to enable cost sharing of projects that are regional in nature and developed to enable compliance with public policy requirements, which include state and federal laws and regulations, and/or to provide economic value, defined as the difference between financially quantifiable benefits related to the provision of transmission service and the project costs.

7.5.1 Multi Value Project Criteria

All Multi Value Projects must satisfy one or more of the criteria outlined below:

7.5.1.1 Multi Value Project - Criterion 1:

An MVP must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the Transmission System to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

7.5.1.2 Multi Value Project - Criterion 2:

An MVP must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section 4.3.9 of this document. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive, and are considered a single type of economic value since LMP savings are a subset of production cost savings. The specific types of economic value that may be considered are listed in Section 8.5.3 of this document.

7.5.1.3 Multi Value Project - Criterion 3:

An MVP must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity reliability standard and must provide economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs. That is, the total MVP Benefit-to-Cost Ratio, as discussed in Section 4.3.9 of this document, must be greater than 1.0.

7.5.2 Multi Value Project Conditions

All Multi Value Projects must satisfy all of the following conditions listed below:

- Must be evaluated as part of a portfolio of projects, as designated in the transmission expansion planning process, whose benefits are spread broadly across the footprint.
- Facilities associated with the transmission project must not be in service, under construction, or approved for construction by the Transmission Provider Board prior to July 16, 2010 or the date the constructing Transmission Owner becomes a signatory member of the ISO Agreement, whichever is later.
- The transmission project must be evaluated through the MISO planning process and approved for construction by the Transmission Provider Board prior to the start of construction, where construction does not include preliminary site and route selection activities.
- The transmission project must not contain any transmission facilities listed in Attachment FF-1 of the Tariff.
- The total capital cost of the transmission project must be greater than or equal to the lesser of $20,000,000.00 or 5% of the constructing Transmission Owner's net transmission plant as reported in Attachment O of the Tariff at the time the transmission project is approved in an MTEP.
- The transmission project must include, but not necessarily be limited to, the construction or improvement of transmission facilities operating at voltages above 100 kV. A transformer is considered to operate above 100 kV when at least two sets of transformer terminals operate at voltages above 100 kV.
- Network Upgrades driven solely by an Interconnection Request, as defined in Attachment X of the Tariff, or a Transmission Service request will not be considered MVPs.

7.5.3 Multi Value Projects - Types of Economic Benefits

The following specific types of economic benefits may be considered when qualifying a project as a Multi Value Project under Criterion 2 or Criterion 3:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements within specific Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the entire MISO.
- Capacity cost savings due to a reduction of system losses during the system peak demand. Capacity cost savings are generated by reducing the overall resource adequacy requirements by an amount equal to the product of the reduced system loss level during the projected system peak demand and one plus the projected Planning Reserve Margin. The economic value of this reduction will be set equal to the projected value of the Cost of New Entrant (CONE).
- Capacity cost savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion. These reductions are typically possible due to relief of transmission congestion and may be determined through execution of Loss of Load Expectation studies.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future due to pursuit of a specific MVProject.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and directly related to providing Transmission Service. Financially quantifiable benefits not directly related to providing Transmission Service, such as economic development benefits and other types of benefits not directly related to providing Transmission Service, cannot be considered in qualifying a project for MVP status.

7.5.4 Multi Value Projects - Other Provisions

The following provisions also apply to Multi Value Projects:

7.5.4.1 Multi Value Projects - Project Type Designation Rule

Should a project qualify as an MVP and also qualify as either a BRP, MEP, or both, the project will be designated as an MVP and not as a BRP or MEP.

7.5.4.2 Multi Value Projects - Like-for-Like Capital Replacement

Should a project be required to facilitate like-for-like capital replacements of plant originally installed as part of an MVP where replacement is i) due to aging, failure, damage or relocation requirements and ii) not the result of negligence by the constructing Transmission Owner, that project will be considered an MVP. The minimum project cost limitation for MVPs described in Section 8.5.2 of this BPM will not apply to the like-for-like capital replacement projects described in this Section.

7.5.5 Multi Value Projects - Cost Allocation

7.5.5.1 Multi Value Projects - Qualification of Facilities for Cost Sharing

Subject to the conditions outlined in Section 8.5.2 of this BPM, any facility associated with an MVP will qualify for cost sharing subject to the following rules:

- Facilities must be considered Network Upgrades and may include any lower voltage facilities that may be needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the MVP.
- Any Network Upgrade cost associated with constructing an underground or underwater transmission line above and beyond the cost of a feasible alternative overhead transmission line that provides comparable regional benefits will not qualify for cost sharing.
- Any DC transmission line and associated terminal equipment will not qualify for cost sharing when scheduling and dispatch of the DC transmission line is not turned over to the MISO markets, real-time control of the DC transmission line is not turned over to the MISO automatic generation control system and/or the DC transmission line is operated in a manner that requires specific users to subscribe for DC transmission service.

7.5.5.2 Multi Value Projects - Allocation of Eligible Costs

One-hundred percent (100%) of the eligible annual revenue requirements of the MVPs shall be allocated on a system-wide basis to Transmission Customers that withdraw energy, including both loads internal to the MISO footprint and External Transactions sinking outside the MISO footprint, excluding transactions that sink in PJM. Also, load serviced under a Grandfather Agreement is excluded from charges for MVPs. The allocation of costs will be in proportion to the metered energy in MWh withdrawn from the Transmission System for internal loads or the energy in MWh scheduled for External Transactions. Eligibility of annual revenue requirements for cost sharing is in accordance with Section 8.5.5.1 of this BPM. These annual revenue requirements will be recovered through a MVP Usage Charge which is described in more detail in the Market Settlements BPM. Revenues collected through this charge will be distributed to the Transmission Owners in accordance with the ISO agreement.

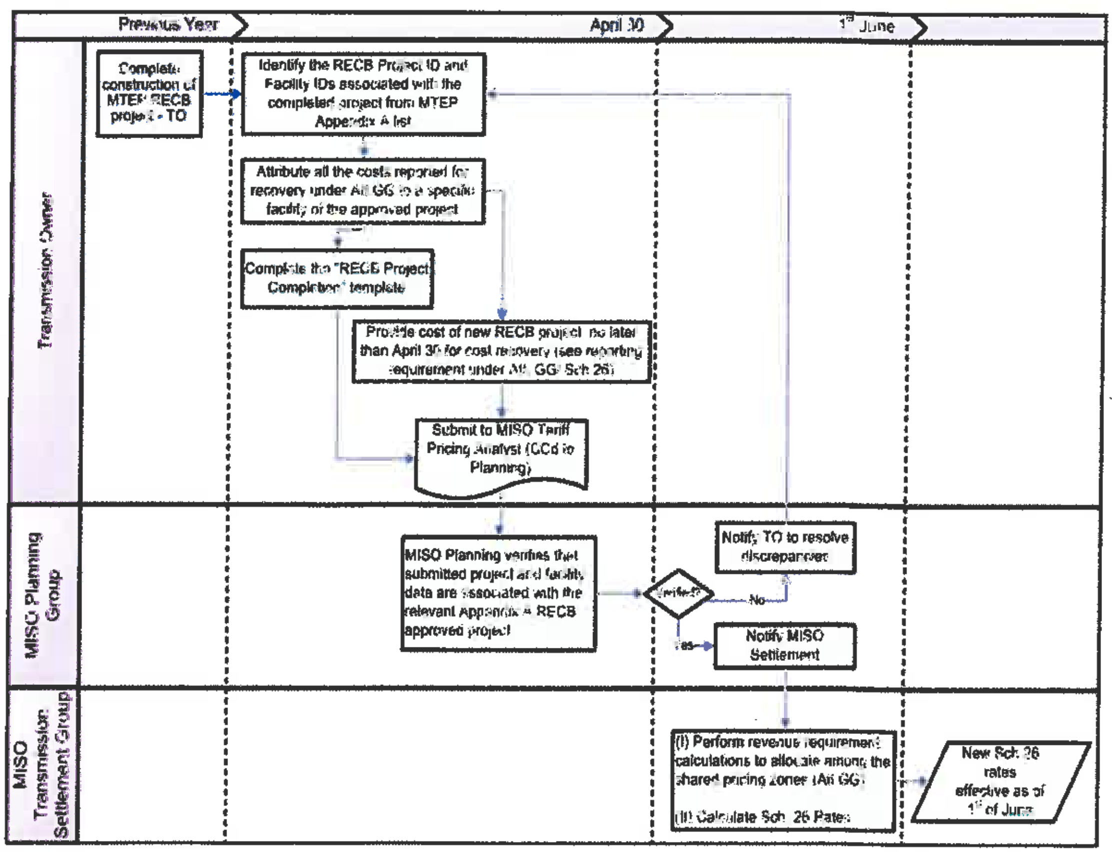
7.6 Project Completion Reporting Guidelines – for Cost Shared Projects

Transmission Owners shall report the MTEP approved cost shared projects (i.e., BRP, GIP, MEP and MVP) upon completion and commissioning of those projects to MISO. This information will be used to verify that only the costs of approved cost shared projects and facilities are charged to other pricing zones through Attachment GG (BRP, GIP and MEP) and Attachment MM (MVP) revenue requirement and rates calculations. Also, the information will be used for the purpose of tracking costs and in-service dates of approved MTEP cost shared projects.

This reporting requirement supplements the annual reporting requirements under Attachment GG and Attachment MM of the Tariff for calculating and collecting the charges associated with Network Upgrades of cost shared projects and for distributing the revenues associated with such charges. Fig. 8.6-1 below shows a high-level process flow diagram with a time-line and associated responsibilities.

A reporting template along with the appropriate contact and submittal information is posted on the Planning page of the MISO web site (https://www.misoenergy.org/Planning/). This template shall also be used for reporting Construction Work In Progress (CWIP) costs associated with MTEP-approved cost shared projects for cost recovery through Attachment GG and Attachment MM of the Tariff by Transmission Owners with FERC approval for recovery of CWIP costs.

Fig 7.6-1: Process Flow for Reporting MTEP Cost Shared Project Costs for Recovery under Att. GG



Note: (1) For certain Transmission Owners (ATC LLC, ITC/METC) who have forward-looking formula rates, the Schedule 26 rates' effective date will be January 1st, requiring a Nov 30th Attachment GG reporting date to MISO. Also, the project costs could include MTEP cost shared project costs projected for the following year.

Appendix A:

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Appendix B: MISO TSR Planning Guideline #1.2 – SIS Report Format

PURPOSE: To provide guidelines for consistent reporting of System Impact Studies associated with requests for long-term firm transmission service under the Tariff.

INTRODUCTION

This guideline is to be followed by MISO planning staff, Transmission Owners, or Third Parties when reporting results of an SIS in order to provide consistency in the reporting of results of such studies.

REPORT OUTLINE

The SIS report shall include the following information:

Executive Summary

This section lists:

1) Type of service requested
2) Whether or not service can be granted at this time
    i. Profile of service, if applicable
    ii. List of milestones for the profile
    iii. List (or point to a list) of transmission system constraints
    iv. Cost to resolve the constraints to service
    v. If there is existing SPS to mitigate the constraints, then the MW reduction of the existing SPS does not exceed its maximum allowable run back with additional transfer.

Introduction

A brief description of the background, purpose, and objectives of the study

Description of Request

The OASIS request information identifying the transaction

Criteria, Methodology, and Assumptions

A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities

Analysis Results

A summary of results of any thermal, voltage, and stability analyses conducted indicating the impact of the request on system performance. Analysis output will be retained and be available for review.

Preliminary Estimate if Direct Assignment or Network Upgrades Required

A listing of any Direct Assignment or Network Upgrade facilities preliminarily determined to be necessary to accommodate the request. A good faith estimate of the customer cost responsibility for such facilities will be determined in a subsequent Facilities Study

Appendix C: MISO TSR Planning Guideline #1.3 – FS Report Format

PURPOSE: To provide guidelines for consistent reporting of Facility Studies associated with requests for long-term firm transmission service under the Tariff.

INTRODUCTION
This guideline is to be followed by MISO planning staff, Transmission Owners, or Third Parties when reporting results of a Facility Study in order to provide consistency in the reporting of results of such studies.

REPORT OUTLINE
The Facility Study report shall include the following information:

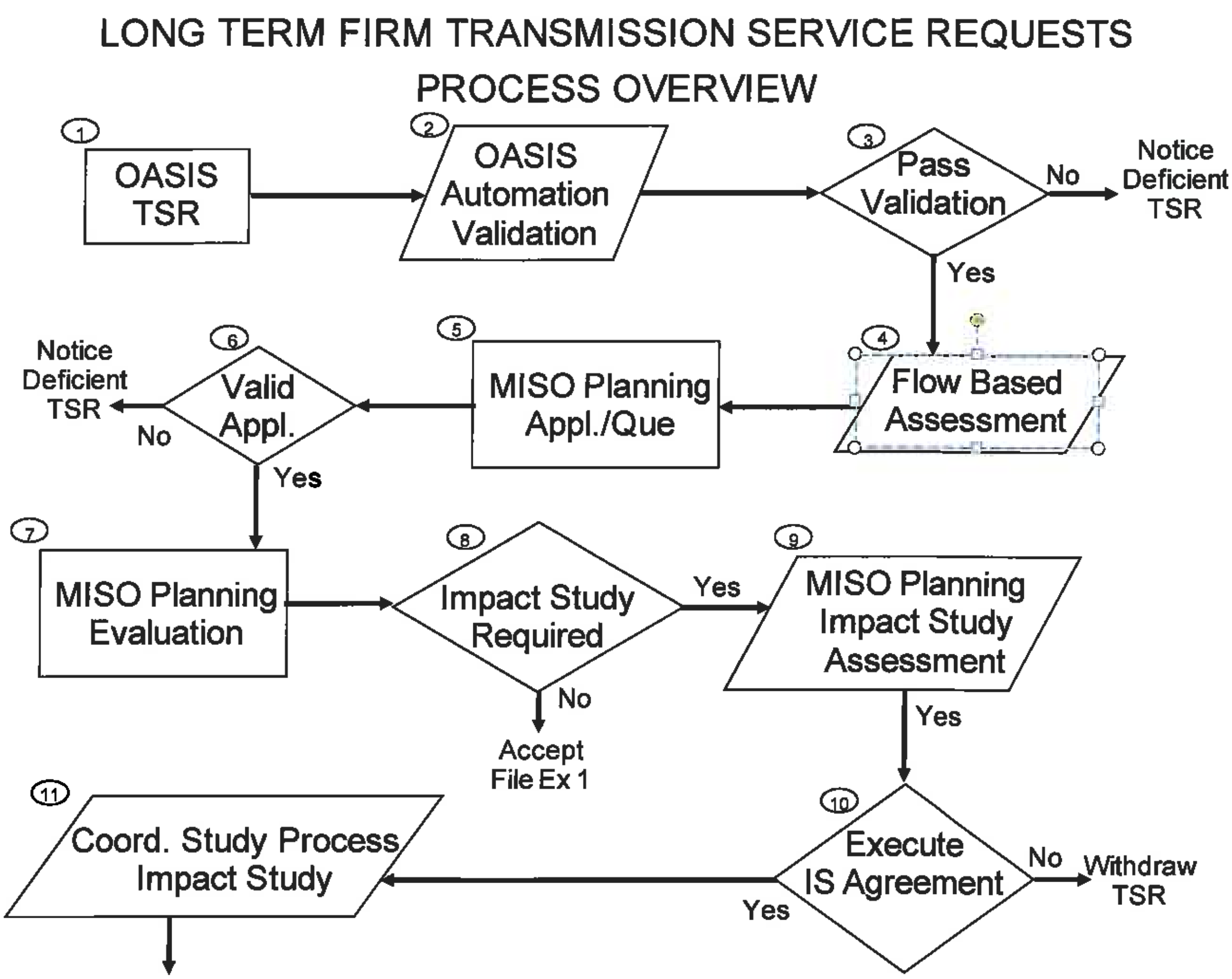
Introduction
A brief description of the background, purpose, and objectives of the study

Description of Request
The OASIS request information identifying the transaction

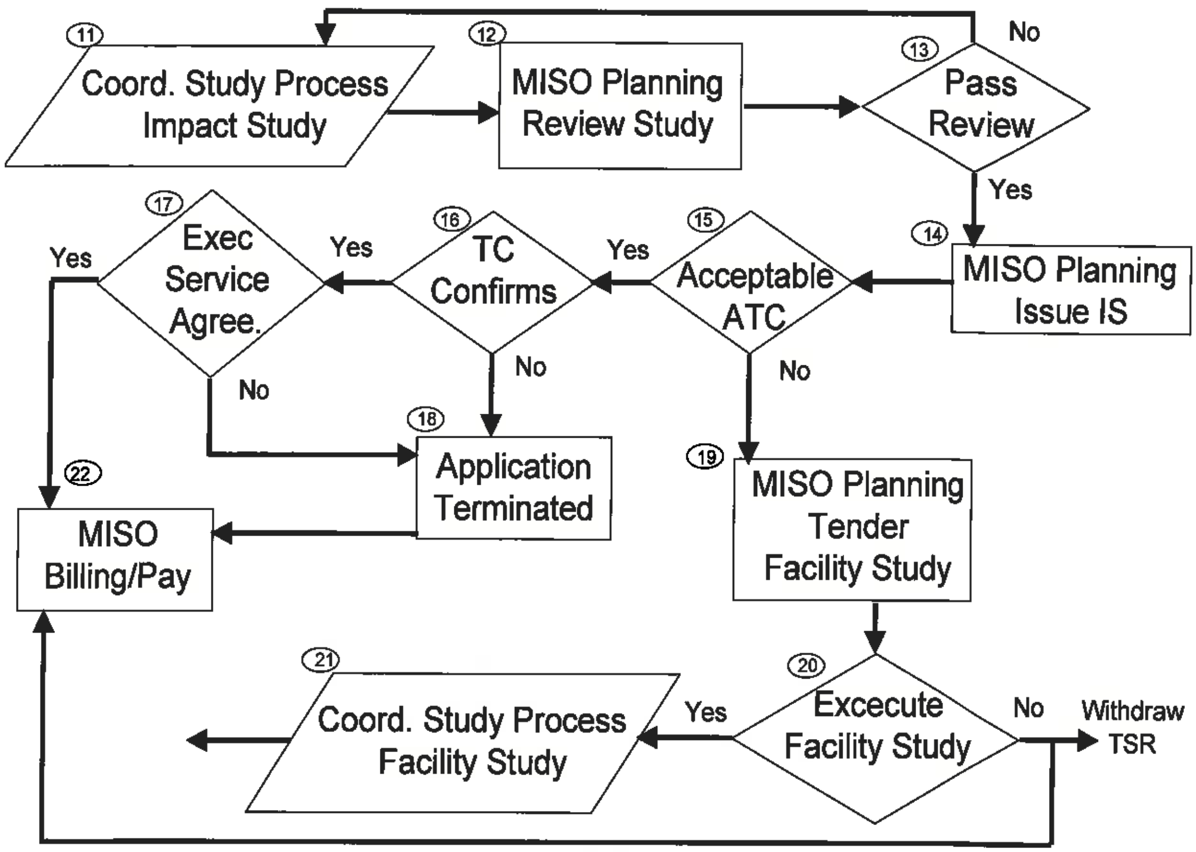
Criteria, Methodology, and Assumptions
A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities. A description of the new/upgrade facilities.

Good Faith Estimate
A detailed statement of the cost of any Direct Assignment Facilities to be charged to the Transmission Customer, the Transmission Customer's appropriate share of the cost of any required Network Upgrades, and the time required to complete such construction and initiate the requested service.

Appendix D: Long-term Firm Transmission Service Requests – Process Overview



LONG TERM FIRM TRANSMISSION SERVICE REQUESTS PROCESS OVERVIEW



Appendix J: Implementation Rules for LODF Calculation and Qualifying System Conditions for Cost Sharing of Baseline Reliability Projects otherwise eligible for Cost Allocation consistent with Attachment FF to the Tariff

The following LODF calculation rules will be applied for Cost Allocation of Baseline Reliability Projects.

J.1 General LODF Methodology and Thresholds

- Use RECB developed "Sum of Absolute value of LODF-Mile" method to develop sub-regional cost allocation percent. LODF values generally determined using MUST LODF function by setting a contingency (outage of the project) and monitored branch lists, or equivalent method. All MISO Transmission Facilities are monitored.
- LODF cutoff rate: 1% (if a monitored branch does not respond by 1% of the project line flow, its impact is ignored)
- Mileage: Line length is reported by Transmission Owner for monitored branches. If not reported, it will be calculated through model impedance and typical values for impedance/mile. Transformers are set to be one mile.
- Only facilities with both terminal 100 kV and above are considered for allocation in the computation
- Tie-lines: Percent ownership as reported by Transmission Owners. Otherwise default owner is non-metered bus terminal in model.
- Where a monitored line is a Remote Line not in the owner's pricing zone the LODF impacts on the Remote Line will be added to the LODF impacts of all other lines of the pricing zone that the Remote Line is in. (See J.4 below)

J.2 Models and Applicable Topology

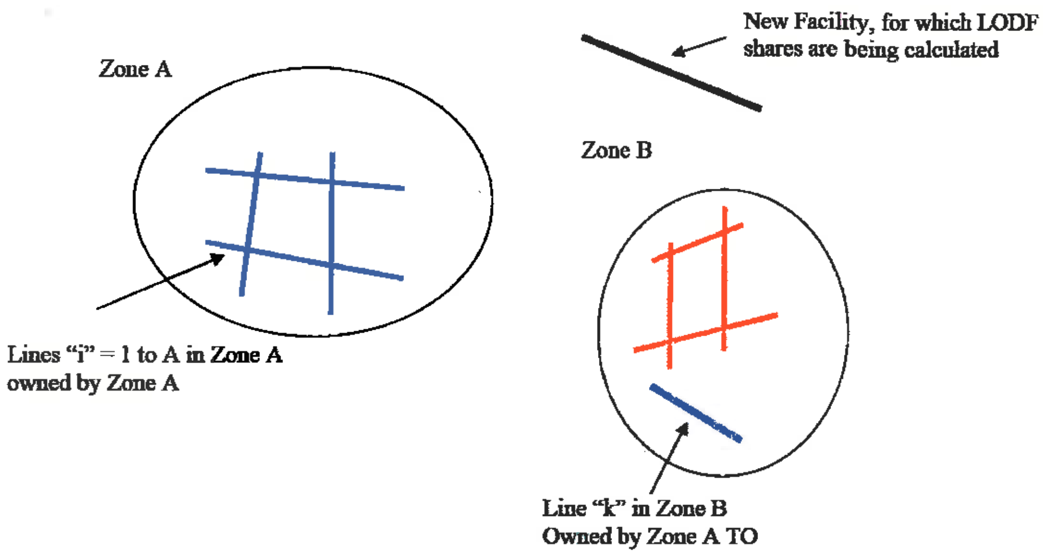
- The current MTEP planning horizon model is used for all project LODF calculations. For example, if a 2011 model is being used for MTEP, and a project is first identified as a required Baseline Reliability Project in that MTEP process, the 2011 model will be used even though the project may have a 2009 service date. This avoids the need to develop many different models for LODF determination, and in any event, such a project will have the LODF calculated under the 2011 topology eventually.
- For each project evaluated, all other Planned and Proposed projects with service dates on or before the MTEP planning horizon year are in the model.
- Both Planned and Proposed Projects that are required to address identified needs will be included in the model. Proposed Projects are included because it is assumed that Proposed Projects or some form of alternative that is not currently known will be required. Proposed Projects to be included in the model are those for which it has been shown that the proposed Project or some alternative is needed to resolve a reliability issue.
- Existing HVDC lines will be modeled as fixed flow with flow controlled to the level set for normal system conditions with the new facility
- Existing Phase Angle Regulators will be modeled as fixed flow with flow controlled to the level set for normal system conditions with the new facility

J.3 Project Specific Methodology

- Only Planned Projects that are Baseline Reliability Projects will be evaluated for cost allocation, although these projects will be evaluated on a model that includes currently identified Planned and Proposed Projects as above. This will avoid requesting MISO to "test the cost allocation waters" as a basis for determining if a Proposed project should be classified as a Planned project to go forward. This determination is better made on the cost effectiveness of the project itself.
- A reconductored line will be simulated as the original line with a parallel pseudo line. LODF will be computed by taking out the parallel line. Alternatively, comparison of line flows between the base system and the change system will be used to develop LODF values.

- Rebuilds involving conversion (removal) of a low voltage facility to a high voltage facility (addition) will compare line flows between the base system and the change system to develop LODF values.
- A series inductor or capacitor will use the same approach as for reconductored lines.
- New capital investments for replacements, or rebuilds due to aging equipment rehabilitation or replacement will not be cost shared.
- Allocations of costs of looped lines will be treated as any other line. A looped (non-radial) line is a networked extension of an existing line to a new substation.
- Cost of terminal upgrades including bus sections, switches, circuit breakers (CB), protection devices, that are an integral part and necessary to integrate a project involving a line or transformer addition or enhancement are lumped with and allocated as per the allocation percentages for the related branch facilities.
- The LODF for upgrades to existing circuit breakers or other interrupting devices that are needed due to increased interrupting duty or continuous loading capability will be defined as 1.0 for all branches in the pricing zone where the circuit breaker is installed, and 0.0 for all other branches. This will result in the costs of these circuit breakers being allocated based on LODF to be 100% local.
- Cost of shunt connected devices (capacitors, SVCs, reactors) required for load serving steady state voltage control or voltage quality will NOT be shared, unless such devices are also needed to remedy stability or to increase transfer capability for reliability purposes (import capability or generator deliverability). Stability and reliability transfer related shunts will be shared 80% Local, 20% Postage Stamp for shunts connected to 345 kV and above (LODF = 1 for local branches, 0 for others), and 100% local for below 345 kV.
- LODF for Projects consisting of multiple branch additions or upgrades will be determined by breaking the project up into its separate branches, and determining the LODF allocation for the cost of each branch. This will avoid masking of proximity effects of the new project (which is the principle of the LODF) where individual branches of a project may have counter-impacts that net to a small impact on nearby facilities. When the LODF is calculated for one of the branches of a multiple branch project, each of the other branches of the project is included in the model, however, the LODF contribution on other branches of the new project are not counted.

- Except for new transformer installations with high side voltages of 345 kV or higher and low side voltages of 344 kV or lower, projects consisting of facilities at multiple voltages, each facility will be evaluated for postage stamp eligibility based on its voltage class.
- Costs of 345 kV or higher voltage substation facilities that are installed as a part of a new transformer installation for transformers with high side voltages of 345 kV or higher and low side voltages of 344 kV or lower, and that are needed only to support a new transformer installation shall be lumped with the cost of the transformer and given the same cost allocation treatment as for the transformer. As an example, a new 345 kV bus and circuit breakers needed to install a new 345/138 kV transformer would not be postage stamped, but would be allocated according to the LODF of the transformer serving the 138 kV system. Costs of related 345 kV equipment such as a line extension to the new 345 kV class substation will be treated on a case-by-case basis depending on the intended future plans for additional networked lines to be installed at the substation. Costs of 345 kV bus and circuit breakers related to new line installations at the same time as the transformer installation will be treated as 345 kV facilities and given the 20% postage stamped treatment.
- Projects or facilities driven solely by contingency loss of, or design violations of, facilities of 69 kV and below will not be cost shared.



$$\text{Share}_{\text{Zone B}} = \frac{\sum^{B} \text{LODF}_j + \text{LODF}_k}{\text{LODF}_{\text{sys}}}$$

J.4 Treatment of Monitored Lines Outside of the Owner's Zone

This is the "Location or Load Based" approach. This will include in the Zone B share the flow impacts of all lines in a Zone B, regardless of line ownership.

J.5 Qualifying System Conditions for Cost Sharing of Baseline Reliability Projects Otherwise Eligible for Cost sharing Under the Tariff

[THIS SECTION RESERVED FOR SPECIFICATIONS TO BE ESTABLISHED BY PS FOR BRP DRIVEN BY SUCH THINGS AS

- NERC C3 CRITERIA
- LOLE ANALYSIS
- NERC PLANNED OUTAGE CRITERIA
- NERC CRITICAL SYSTEM CONDITIONS CRITERIA IN GENERAL
- ETC]

J.5.1 Cost Sharing Treatment of Baseline Reliability Projects Justified Based on NERC Category C3[2] Contingencies

Under Attachment FF to the TEMT, costs of Baseline Reliability Projects included in the MTEP and for which (1) the Network Upgrade has a Project Cost of $5 million or more or (2) the Network Upgrade has a Project Cost of under $5 million and is five percent (5 %) or more of the Transmission Owner's net plant as established in Attachment O of the Tariff, shall be subject to the cost sharing provisions of Attachment FF. Attachment FF defines Baseline Reliability Projects as "Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region."

[2] NERC Category C3 is a designation in the Approved Version 0 of the NERC Standards TPL-003-0.